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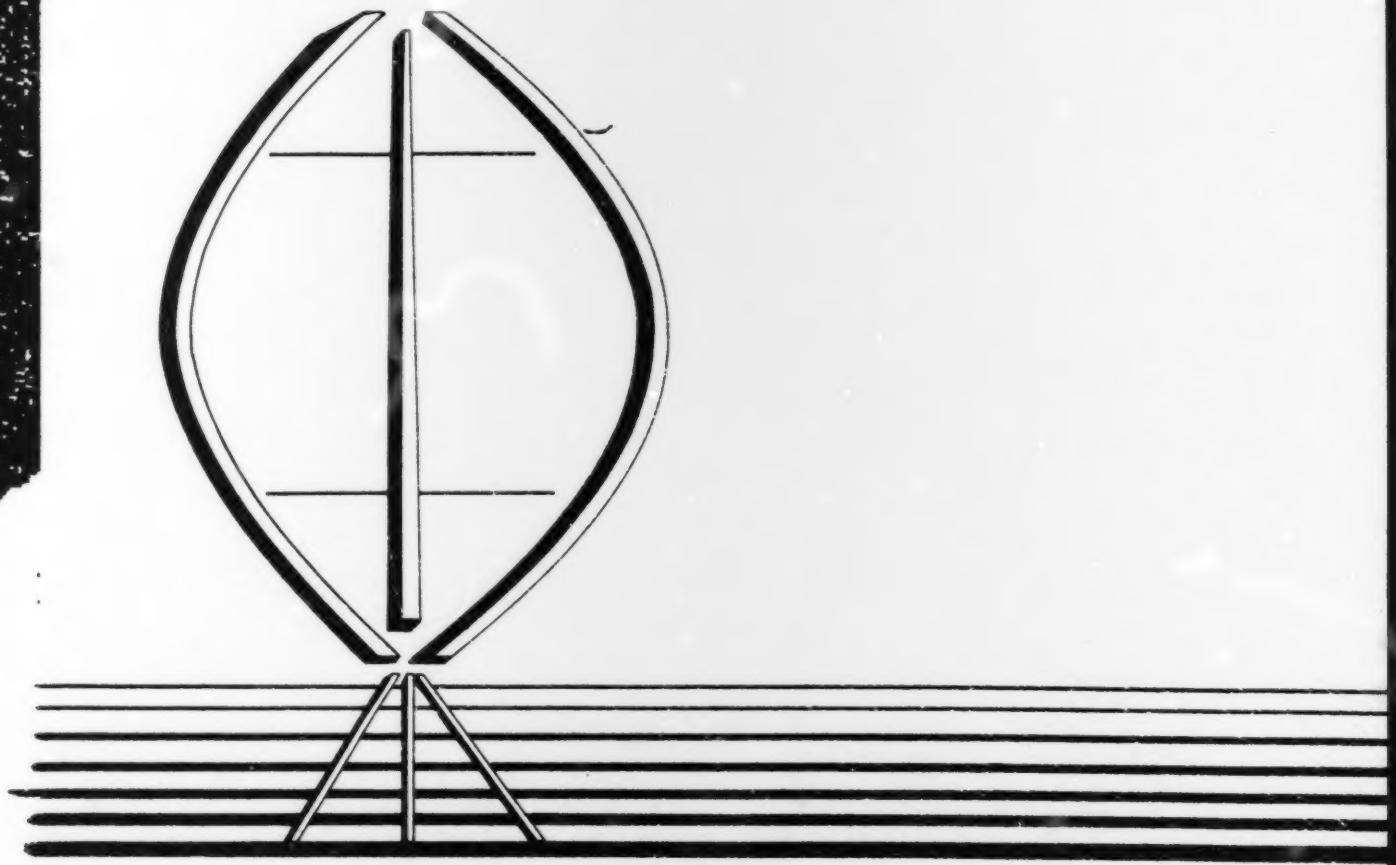
Technical Memorandum

Assessment of Performance and Cost-effectiveness of Wind Energy Conversion Systems

M.S. Chappell and R.J. Templin

October 1984



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ASSESSMENT OF PERFORMANCE AND COST-EFFECTIVENESS OF WIND ENERGY CONVERSION SYSTEMS

M.S. Chappell and R.J. Templin

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OCTOBER 1984

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SUMMARY

The cost-effectiveness of any wind energy conversion system (WECS) depends on four major factors:

- the wind regime at the site
- the performance of the WECS
- the installed cost of the WECS
- the projected operational/financial scenario

These four factors are discussed briefly, and a methodology is developed to quickly assess the cost of electricity from candidate WECS installations, within the bounds of certain simplifying assumptions. In addition, a multiparameter nomograph is presented which enables simple and convenient WECS cost/effectiveness assessments to be made, based on brochure-type information and without any significant arithmetic calculations.

The methodology presented is not a rigorous economic analysis involving Present Value tabulations of future costs and benefits, costs of alternative energy sources, and cashflow scheduling. Rather, it is a simple technique for assessing the cost of electricity produced by a candidate WECS, so that a prospective owner may quickly determine the likely financial viability of such an installation, and may appreciate the relative importance of the major parameters which will affect its performance. Indeed, this simple method of assessment could well indicate the desirability of more sophisticated economic and performance analyses.

RÉSUMÉ

La rentabilité de tout système de conversion d'énergie éolienne (SCEO) dépend de quatre grands facteurs:

- le régime éolien de l'endroit
- le rendement du SCEO
- les frais d'installation du SCEO
- le plan du financement et de fonctionnement prévu

Ces quatre facteurs sont abordés et une méthodologie est mise de l'avant afin d'évaluer rapidement le coût en électricité des installations de SCEO à l'étude, d'après certaines prévisions de base. De plus, on explique le fonctionnement d'un nomographe multi-paramètres permettant d'effectuer des évaluations simples et appropriées de la rentabilité du SCEO, tirées de l'information contenue dans une brochure et sans avoir à effectuer des calculs arithmétiques compliqués.

La méthodologies présentéé ici n'est pas une analyse économique rigoureuse recourant à un système de tabulations de la valeur actuelle des coûts et avantages futurs, des coûts des sources d'énergie de rechange et du calendrier des mouvements de caisse. C'est plutôt une technique simple en vue d'évaluer le coût de l'électricité produite par un SCEO, de façon à ce qu'un propriétaire éventuel puisse déterminer rapidement la rentabilité financière probable d'une installation de ce genre, et puisse connaître l'importance relative des principaux paramètres modifiant son rendement. Cette méthode d'évaluation pourrait, en effet, encourager la poursuite d'analyses économiques et de rendement plus poussées.

ASSESSMENT OF PERFORMANCE AND COST-EFFECTIVENESS OF WIND ENERGY CONVERSION SYSTEMS

M.S. Chappell and R.J. Templin

1.0 INTRODUCTION

The cost-effectiveness of a wind energy conversion system (WECS) installation depends on many parameters. Moreover, there are many different methodologies used to calculate the cost-effectiveness of actual or proposed WECS installations. Such methods range from simple payback estimates typically used in assessing domestic applications, to sophisticated network dispatch simulations used by electric utility agencies to assess the potential for significant wind energy contributions to major grid systems. This report outlines a simple procedure which takes account of most significant parameters that affect cost-effectiveness, and presents some discussion and illustrations of their relative importance and sensitivities.

The four major factors which govern the economics of wind energy installations are

- the wind regime at the site
- the performance of the WECS
- the installed cost of the WECS
- the projected operational/economic scenario

These factors and their interrelations are discussed in the following chapters. Introduction of certain simplifying, yet realistic, approximations allows a convenient assessment technique for WECS cost-effectiveness to be developed and presented in the format of a multi-parameter nomograph, which illustrates the sensitivities of most major parameters. A few example cases are cited to demonstrate the techniques.

2.0 WIND REGIME

2.1 Variation with Height

Wind is a manifestation of solar energy resulting from differential heating of parts of the earth's atmosphere and the consequent movement of air masses from high to low density regions. To the height of even the largest earth-mounted wind energy conversion systems (WECS), the flow regime is within the atmospheric boundary layer. Thus local flow is affected by nearby topography and the velocity usually increases with height above the ground as shown in FIGURE 1.

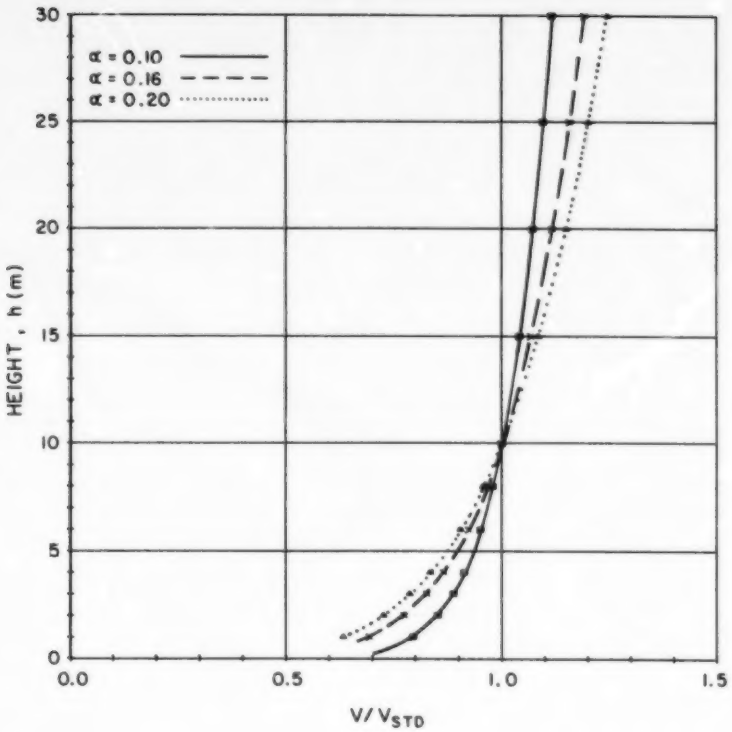

Fig. 1. Wind velocity variation with height

In general the velocity dependence on local height above the ground is exponential and can be expressed as

$$V_2/V_1 = (h_2/h_1)^{\alpha}$$

where the exponential coefficient α depends on the upwind topography. Commonly used values are

$\alpha = 0.10$	for water or very flat land
$\alpha = 0.16$	for rolling terrain
$\alpha = 0.20$	for hilly or urban areas

Standard meteorological wind velocity data are obtained at or corrected to 10 m height. Thus it is common practice to estimate wind velocity at wind turbine hub height from

$$V_{HUB}/V_{STD} = (h_{HUB}/10)^{\alpha}$$

where h_{HUB} is the wind turbine hub height (m) and α is chosen appropriately for the site topography.

It is seen that, for $\alpha = 0.16$, wind velocity increases by about 12% for each doubling of height above the ground.

2.2 Variation with Time

There are significant changes of wind velocity with time ranging from seasonal variations, through daily fluctuations related to day/night patterns, to gusts of only a few minutes duration, and turbulence with time constants of the order of 1 s. These fluctuations are illustrated on FIGURE 2 based on data from a single well-instrumented site.

The time history of wind speed for a prescribed period is usually expressed as a histogram of duration vs. velocity as shown in FIGURE 3. Each bar represents the aggregate duration of all intervals during which the wind velocity was within certain limits. Wind speed "bins" are typically 0.5 m/s width, and most automatic logging systems sample windspeed every 1 or 2 s.

In the limit, as the width of the wind speed "bins" becomes narrower and narrower, the step-like histogram becomes a smooth curve (FIGURE 3). Mathematically, this curve can be described as a Weibull distribution function

$$P_{V/V_{av}} = k[\Gamma(1 + 1/k)]^k (V/V_{av})^{k-1} \exp\left\{-[\Gamma(1 + 1/k)(V/V_{av})]^k\right\}$$

where

$P_{V/V_{av}}$ = probability of wind velocity V as a ratio of the average wind velocity V_{av}
Γ = mathematical gamma function
k ≡ the Weibull Coefficient

The time-variance of wind speed can this be characterized by an appropriate value of the Weibull coefficient k. FIGURE 4 shows the probability/velocity distribution for three wind regimes with different Weibull Coefficients.

The value k = 2.0 has been found to be typical of many potential wind turbine sites. This particular value allows some arithmetic simplifications to the Weibull equation and is termed a "Rayleigh Distribution." Lacking specific knowledge of the site velocity/duration characteristics, it is common practice to assume a Rayleigh distribution. However, as presented in Section 3.4, the actual value of k can significantly affect energy output from the wind turbine.

2.3 Sources of Data

Many data have already been accumulated on wind as part of long term meteorological records throughout most populated parts of Canada. The

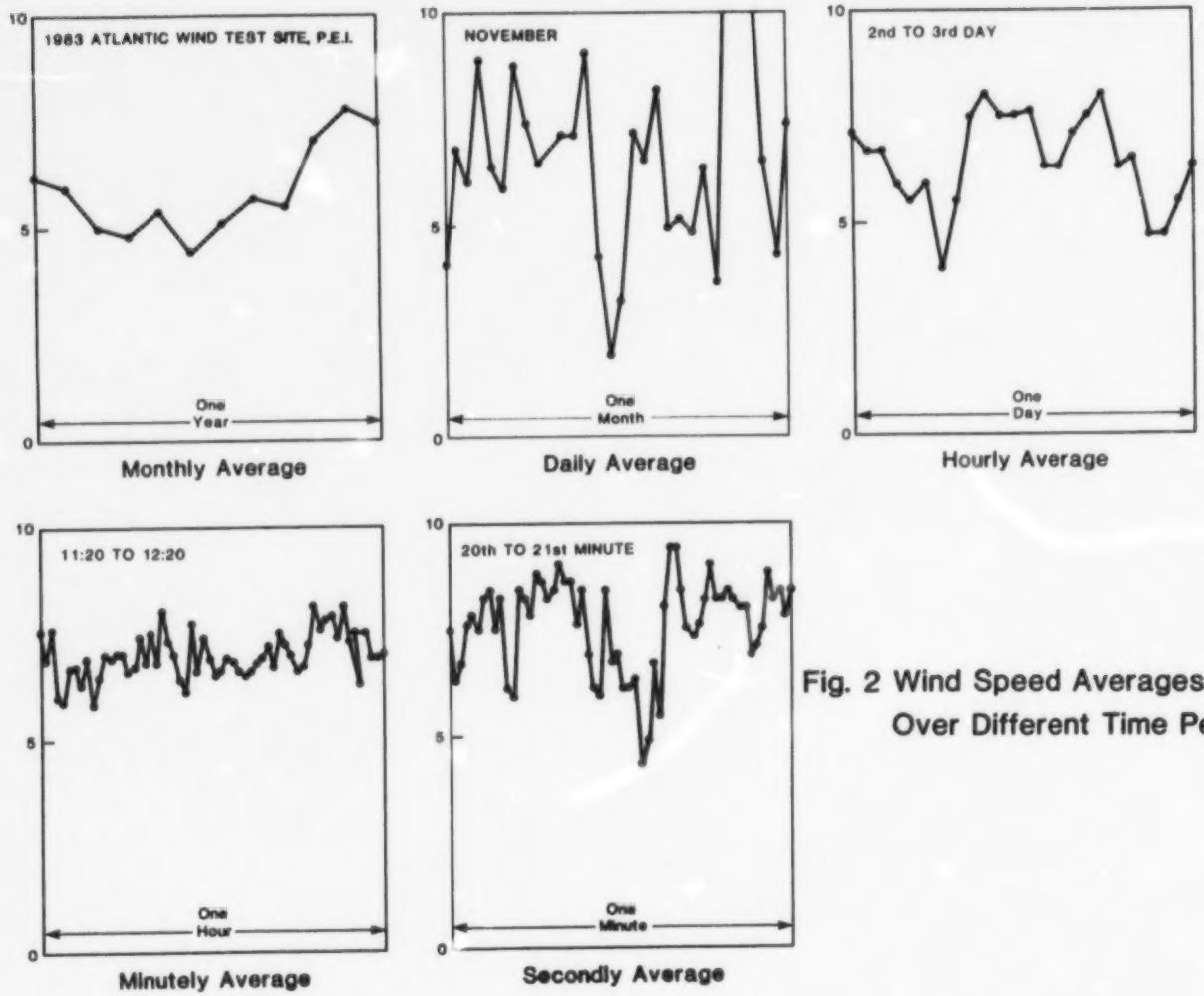

Fig. 2 Wind Speed Averages Over Different Time Periods

Fig. 2. Wind speed averages over different time periods

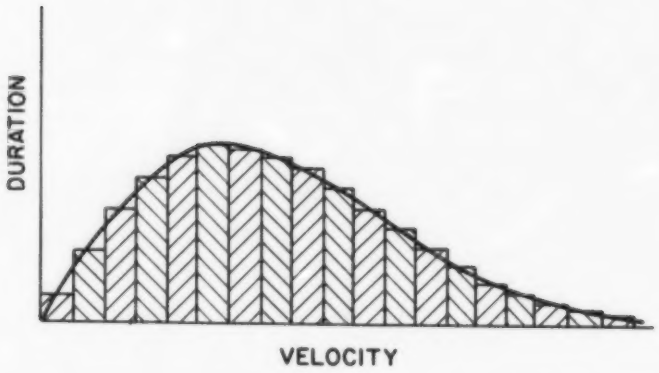

Fig. 3: Wind speed/duration histogram

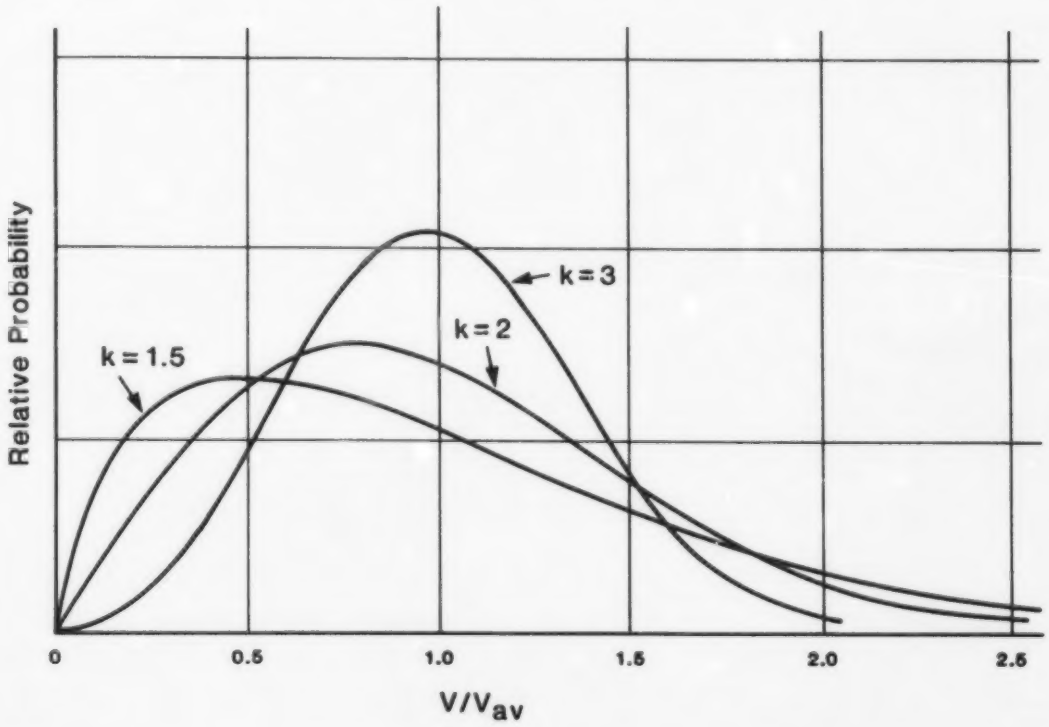

Fig. 4. Temporal distributions of wind velocity

Atmospheric Environment Service (AES) of Environment Canada has published Canadian Climate Normals of which Volume 5 provides monthly values of wind speed and wind direction at about 400 locations. Data from this and other sources have now been reworked and a series of reports will be issued shortly providing detailed regional data on wind energy densities and other parameters particularly suitable for wind energy users (FIGURE 5).

SUDBURY A, ONT — LATITUDE: 46°38'N; LONGITUDE: 80°48'W/0; ALTITUDE: 348 m

WIND SUMMARY ANALYSIS PERIOD: 1967 JA to/a 1976 DE — SOMMAIRE DU VENT PERIODE D'ANALYSE

MEAN WIND SPEED (km/h) — TABLE (iv) / TABLEAU (iv) — VITESSE MOYENNE DU VENT (km/h)

DIRECTION	JA	FE	MR	AL	MA	JN	JL	AU	SE	OC	NO	DE	AN
N	25	28	28	27	23	22	20	21	20	25	26	29	25
NNE	21	24	25	23	22	22	20	19	21	22	28	25	23
NE	21	20	21	21	19	18	16	17	17	20	23	20	19
. .	.	.	.	.	.	.	.	.	.	.	.	.	.
. .	.	.	.	.	.	.	.	.	.	.	.	.	.
. .	.	.	.	.	.	.	.	.	.	.	.	.	.
NNW NNO	24	26	27	26	21	20	20	18	20	21	23	25	23

MEAN WIND SPEED FROM ALL DIRECTIONS (km/h): 20.5 | 20.7 | 21.5 | 21.8 | 19.2 | 18.5 | 17.9 | 17.0 | 17.2 | 19.1 | 20.1 | 20.8 | 19.5
VITESSE MOYENNE DU VENT POUR TOUTES LES DIRECTIONS

EFFECTIVE MEAN WIND SPEED** (km/h): 25.8 | 26.0 | 26.2 | 26.0 | 23.1 | 22.7 | 22.0 | 20.8 | 21.8 | 23.5 | 24.6 | 26.1 | 24.2
***VITESSE MOYENNE EFFECTIVE DU VENT

** The EFFECTIVE MEAN WIND SPEED is the cube root of the mean cubed wind speed
*** La VITESSE MOYENNE EFFECTIVE DU VENT est la racine cubique de la moyenne du cube de la vitesse du vent.

MEAN DIRECTED WIND POWER (W/m²) — TABLE (v) / TABLEAU (v) — PUISSANCE MOYENNE DU VENT SELON LA DIRECTION (W/m²)

DIRECTION	JA	FE	MR	AL	MA	JN	JL	AU	SE	OC	NO	DE	AN
N	413	478	479	362	245	226	159	181	193	321	380	465	342
NNE	355	365	391	241	203	246	162	139	245	235	458	374	283
NE	218	176	234	179	131	116	79	110	114	172	226	201	170
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. .	.	.	.	.	.	.	.	.	.	.	.	.	.
NNW NNO	315	377	374	361	204	155	168	128	173	232	219	336	273

MEAN WIND POWER FROM ALL DIRECTIONS (W/m²): 236 | 252 | 243 | 232 | 158 | 146 | 132 | 113 | 131 | 169 | 197 | 244 | 187
PUISSANCE MOYENNE DU VENT POUR TOUTES LES DIRECTIONS

SUDBURY A, ONT — LATITUDE: 46°38'N; LONGITUDE: 80°48'W/0; ALTITUDE: 348 m

WIND SUMMARY ANALYSIS PERIOD: 1967 JA to/a 1976 DE — SOMMAIRE DU VENT PERIODE D'ANALYSE

MEAN DIRECTED WIND ENERGY (MJ/m²) — TABLE (vi) / TABLEAU (vi) — ENERGIE MOYENNE DU VENT SELON LA DIRECTION (MJ/m²)

DIRECTION	JA	FE	MR	AL	MA	JN	JL	AU	SE	OC	NO	DE	AN
N	102	138	167	131	65	45	3[illegible]	36	43	80	81	136	1037
NNE	45	95	96	69	54	54	24	19	32	26	76	59	659
NE	34	26	39	35	30	16	8	14	12	22	45	45	324
. .	.	.	.	.	.	.	.	.	.	.	.	.	.
. .	.	.	.	.	.	.	.	.	.	.	.	.	.
. .	.	.	.	.	.	.	.	.	.	.	.	.	.
NNW NNO	71	73	79	71	24	13	22	18	28	33	36	80	548

MEAN WIND ENERGY FROM ALL DIRECTIONS (MJ/m²): 632 | 595 | 651 | 602 | 424 | 378 | 353 | 302 | 340 | 452 | 512 | 654 | 5896
ENERGIE MOYENNE DU VENT POUR TOUTES LES DIRECTIONS

RECORDED WIND ENERGY (MJ/m²) — TABLE (vii) / TABLEAU (vii) — ENERGIE ENREGISTREE DU VENT (MJ/m²)

YEAR/ANNEE	JA	FE	MR	AL	MA	JN	JL	AU	SE	OC	NO	DE	AN
1967	935	1127	580	722	477	286	230	271	530	736	526	799	7208
1968	715	750	782	789	292	320	547	382	245	377	624	1219	7043
1969	597	526	788	474	412	400	218	248	116	332	422	517	5051
.	.	.	.	.	.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.	.	.	.	.	.
1976	520	569	639	544	457	306	417	304	418	440	369	554	5536
MEAN OF RECORDED ENERGY (MJ/m²)	632	595	651	602	424	378	353	302	340	452	512	654	5896
STANDARD DEVIATION OF RECORDED ENERGY (MJ/m²)	211	230	156	165	80	128	93	42	118	160	119	252	876

MOYENNE DE L'ENERGIE ENREGISTREE

ECART TYPE DE L'ENERGIE ENREGISTREE

SUDBURY A, ONT — LATITUDE: 46°38'N; LONGITUDE: 80°48'W/0; ALTITUDE: 348 m

WIND SUMMARY ANALYSIS PERIOD: 1967 JA to/a 1976 DE — SOMMAIRE DU VENT PERIODE D'ANALYSE

HOURLY MEAN WIND POWER (W/m²) — TABLE (viii) / TABLEAU (viii) — MOYENNE HORAIRE DE LA PUISSANCE DU VENT (W/m²)

HOUR/HEURE	JA	FE	MR	AL	MA	JN	JL	AU	SE	OC	NO	DE	AN
0	217	255	201	173	102	85	66	55	96	130	168	231	148
1	214	263	197	168	96	84	66	54	83	124	165	232	144
2	219	273	199	168	93	85	63	53	89	125	166	232	145
.	.	.	.	.	.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.	.	.	.	.	.
.	.	.	.	.	.	.	.	.	.	.	.	.	.
23	226	246	210	176	105	87	67	64	94	136	177	234	150
MONTHLY MEAN WIND POWER (W/m²)	236	252	243	232	158	146	132	113	131	169	197	244	187

MOYENNE MENSUELLE DE LA PUISSANCE DU VENT

Fig. 5. Sample wind data from publications by Environment Canada

3.0 WECS PERFORMANCE

3.1 Power Output

Typical WECS performance curves are shown in FIGURE 6, which also serves to define salient values often quoted in WECS specifications.

The numerical value of the power output depends on the size of the windmill and its overall efficiency; the latter usually expressed as Coefficient of Performance, C_p, where

$$Cp \equiv \frac{\text{output power}}{\text{aerokinetic energy approaching the rotor swept area}}$$

$$= \frac{P}{\frac{1}{2}\rho A V^3}$$

where

P = power output (kW)
ρ = air density (kg/m^3)
A = rotor swept area (m^2)
V = free stream wind velocity (m/s)

Most modern wind turbines incorporate carefully designed airfoils, reasonably efficient drive trains, and moderately optimal controls. State-of-the-art technology in both horizontal axis wind turbines (HAWT) and vertical axis wind turbines (VAWT) yields maximum Coefficients of

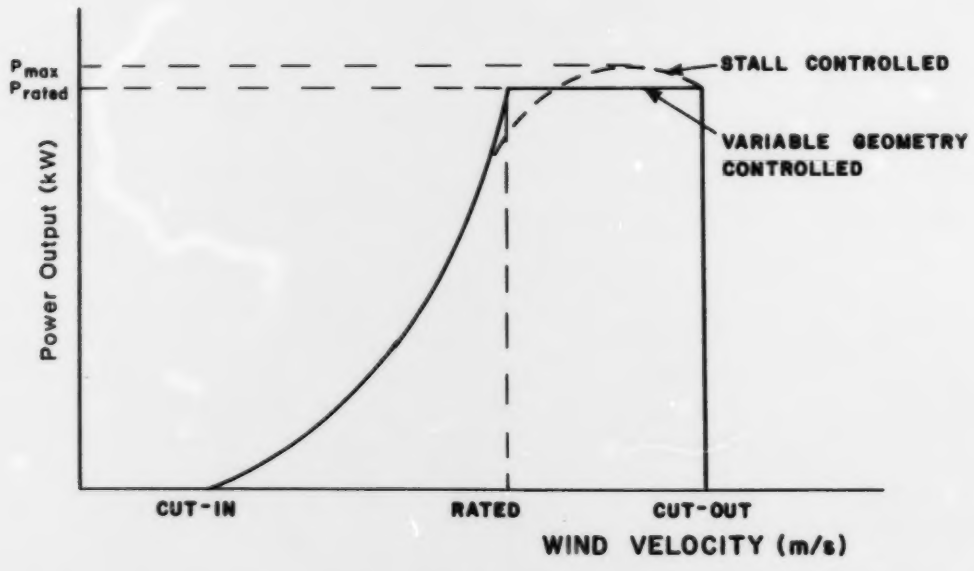


Fig. 6. Typical WECS performance curves

Performance of about 0.42, compared to a theoretical maximum of 0.593 for unshrouded rotors. Hence, all modern, carefully designed and fabricated windmills will produce roughly the same energy output per square metre of swept area if they are installed at the same height in the same wind regime. Some variations can be expected depending on how system design was optimized relative to the intensity of the wind regime at the particular site. This will be discussed in more detail later.

3.2 Energy Output

Energy output per year can be computed by piecewise integration of the WECS power curve and the windspeed-duration curve that describes the site wind regime. This process is illustrated in FIGURE 7. From the site wind regime curve it is determined that the wind velocity is V for a total of T hours per year. From the WECS performance curve it is determined that at wind velocity V the WECS produces P kilowatts of power. Thus the energy produced during the whole year at wind velocity V is P × T kWh. Repeating this calculation for all wind velocities between CUT-IN and CUT-OUT wind speeds and summing the energy values gives the total annual energy output for that WECS in that wind regime, assuming the machine is available to operate at all times (i.e., no down time).

TABLE 1 has been constructed by doing such calculations, based on a typical modern WECS performance curve, for a range of windspeeds and values of P_{max} per unit of swept area and a CUT-OUT velocity of 22.4 m/s (50 mph). All values are quoted per unit of swept area and thus apply to all sizes of WECS. Moreover, by quoting values of windspeed at rotor center, the effects of tower height have been incorporated.

Table 1. Annual energy output per unit swept area for well designed modern WECS (cut-out wind velocity 22.4 m/s)

Annual average wind velocity at rotor centre, (k=2.0), (m/s)	Annual energy output per unit swept area ($MWh/m^2 \cdot yr$) for power loading (W/m^2), P_{max}/A =			
	250	500	750	1000
4	0.175	0.143	0.111	0.081
5	0.345	0.341	0.311	0.269
6	0.538	0.605	0.602	0.570
7	0.729	0.903	0.951	0.956
8	0.904	1.205	1.338	1.390
9	1.050	1.479	1.703	1.817
10	1.160	1.708	2.018	2.197

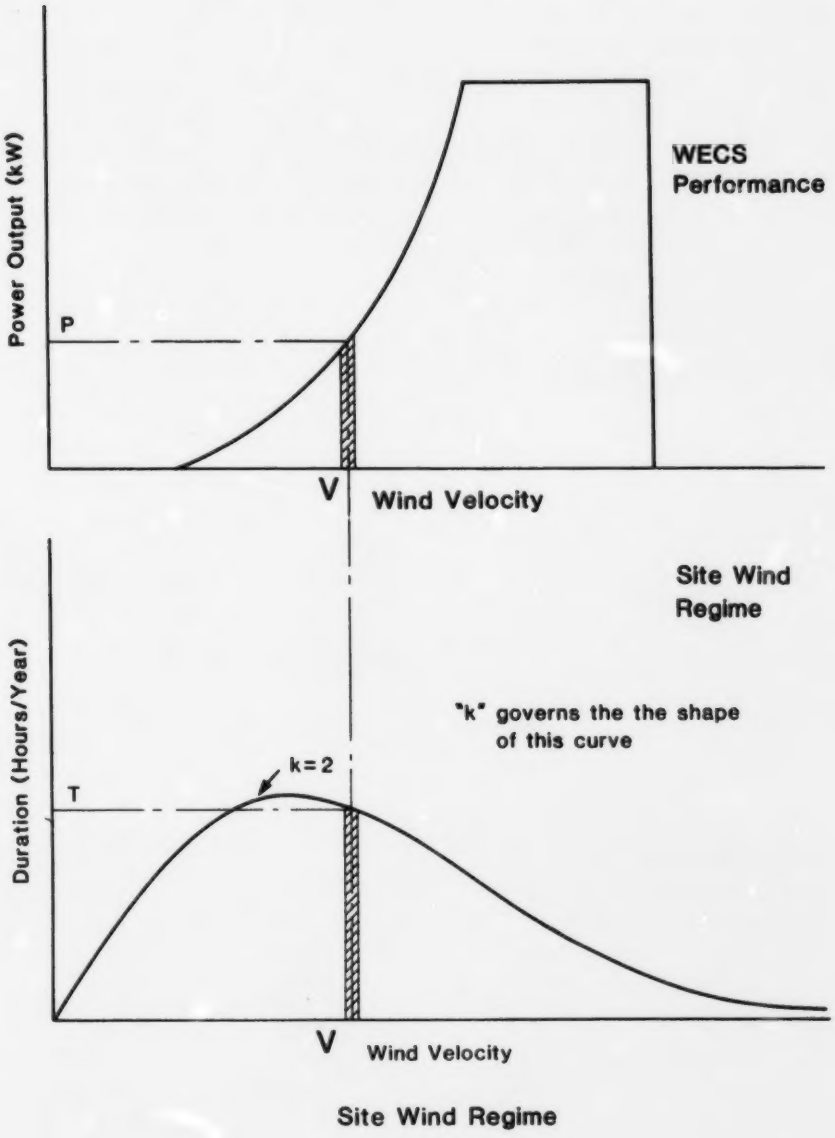


Fig. 7. Energy output calculation

3.3 Effects of Power Loading

In TABLE 1, the parameter Power Loading $\equiv P_{max}/A$ (W/m^2) is a measure of the designer's choice of how large a generator to attach to a given size of rotor. The energy yield is somewhat sensitive to this parameter as a very big generator coupled to a given rotor will only be effectively utilized in very strong winds, thus in a poor or moderate wind regime such a

"mismatched" system will actually produce **less** energy than the **same rotor** driving an appropriately **smaller** generator. This is illustrated quantitatively in FIGURE 8, derived from TABLE 1.

From these graphs it is evident that significant penalties can be incurred if power loading is not chosen appropriately for the site wind regime. In poor wind regimes (with annual average wind velocity $\bar{V} < 5$ m/s) power loadings should be kept below 250 W/m^2. In moderate wind regimes, energy yield is less sensitive to power loading, and units with power loadings between 500 and 750 W/m^2 yield within ±10% of the same energy output over a range of average windspeeds from 5 to 7 m/s. In energetic wind regimes with annual average windspeeds over 7 m/s, power loadings of 750 W/m^2 and above are appropriate.

Alternatively, for the ranges of parameters shown on the graphs, a power loading of 500 W/m^2 results in a 25% loss of energy yield at 4 m/s annual average windspeed, optimum yield at about 5.5 m/s, and a loss of 30% in energy yield at 10 m/s, compared with optimum values of power loading in each case.

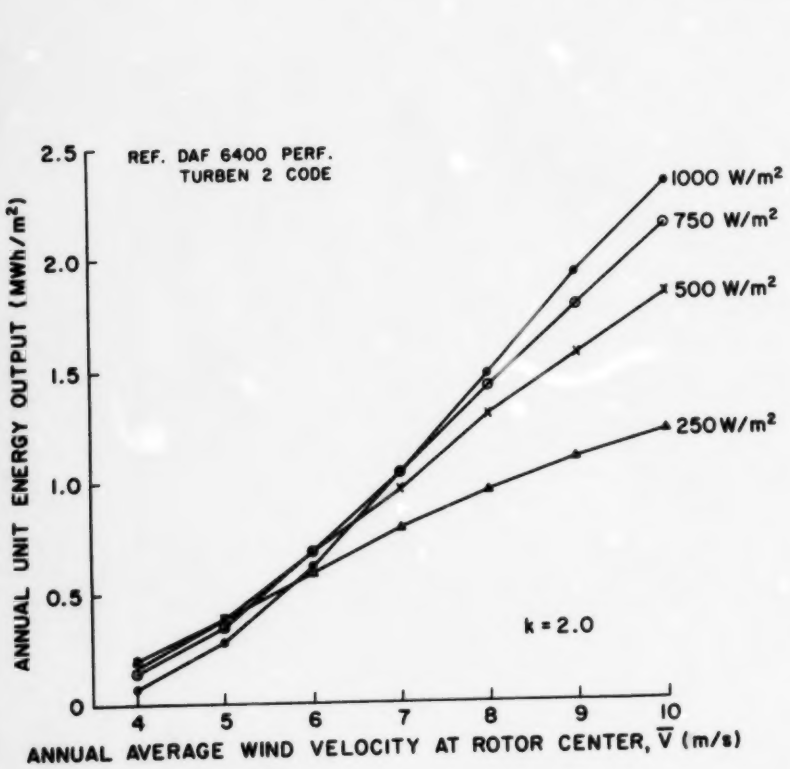
Rough optima are shown to be:

Annual Average Windspeed	Power Loading
<5 m/s	<250 W/m^2
5 → 6 m/s	500 W/m^2
6 → 7 m/s	750 W/m^2
>7 m/s	>1000 W/m^2

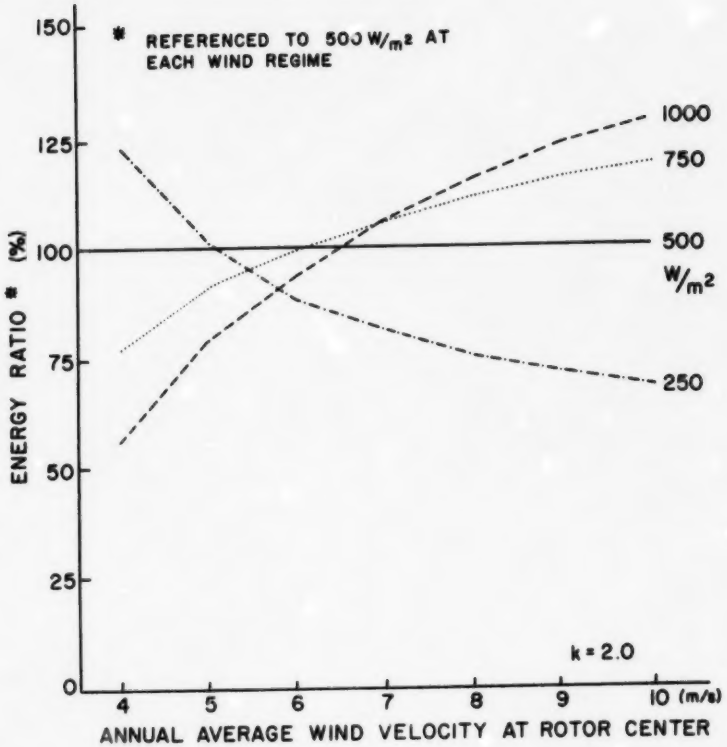
In addition to total energy yield, power loading affects the operational behaviour of the WECS. A machine with high power loading will tend to provide high power output for relatively short periods of time (during very high windspeeds). A machine with somewhat lower power loading may indeed generate the same amount of total energy yield but at lower power output over longer periods of time. The latter is usually preferable and hence, all else being equal, the machine with the lower power loading (within the "roughly optimum" range) is often the wiser choice. The significance of so-called "Plant Factor" is further illustrated in Sections 5 and 6.

3.4 Effects of Non-Rayleigh Windspeed Distribution

It is common practice in estimating WECS performance to assume the Rayleigh distribution ($k = 2.0$) for the velocity-duration curve describing the wind regime. This approximation is justified in many instances; however, non-Rayleigh distributions have been observed at some sites although no quantitative correlation of k value and topographical features has yet been established. The effect of non-Rayleigh windspeed distribution on



(a)



(b)

Fig. 8. Effects of power loading on energy output as a function of wind velocity. (a) Annual energy output per unit swept area. (b) Relative energy output

energy yield is not negligible and depends also on the average wind velocity. Again using typical current-technology WECS performance, the energy ratio for non-Rayleigh k has been computed and is plotted as a function of annual average windspeed in FIGURE 9.

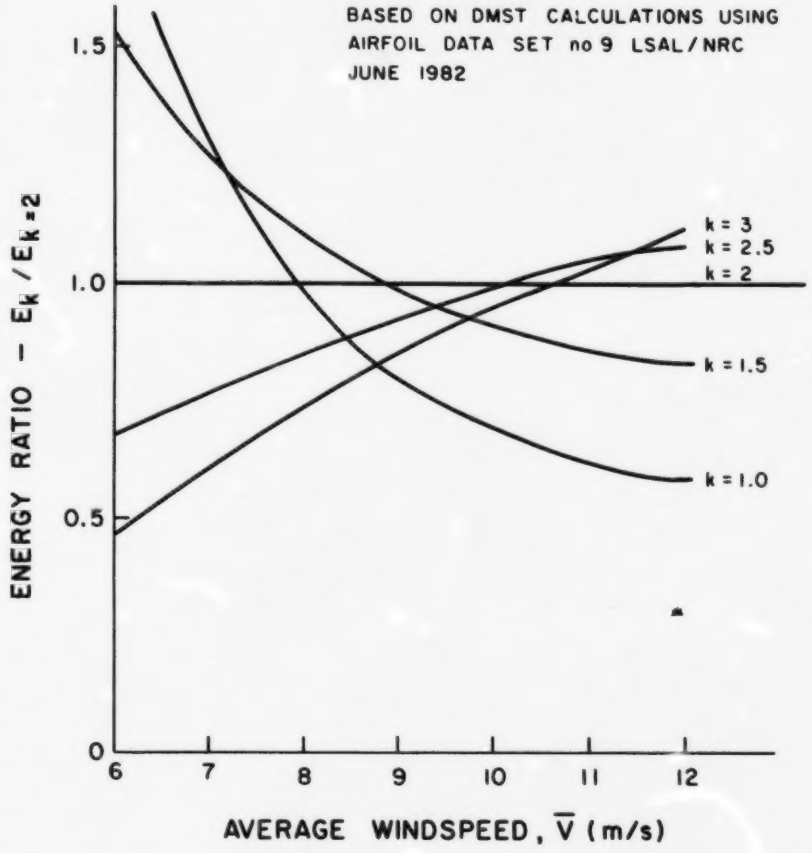


Figure 9. Effect of Weibull coefficient k on WECS energy output

The significance of non-Rayleigh values of the Weibull Coefficient k is seen to be greatest at low and moderate average windspeeds. Except in extremely energetic wind regimes, energy yield is greatest at $k < 2.0$. Indeed, the energy output gain is substantial if $k < 1.5$ in moderate wind regimes with $\bar{V} < 6$ m/s.

4.0 WECS COSTS

The annual cost of a WECS installation comprises two elements, viz:

- the cost of ownership - which reflects the initial capital cost of the complete WECS system and the annual interest charged, or rate of return demanded

- the operating and maintenance (O&M) cost - which includes inspections, repairs, and consumables (such as oil) plus all labour costs including transportation of personnel and replacement parts to the site

These values differ greatly from installation to installation, depending not only on the site and the WECS hardware, but also on the perceptions of the assessor or owner. Enthusiasts tend to downplay both the costs of ownership ("once the windmill is paid for, the energy is free") and O&M costs ("it doesn't cost a penny to run, I look after it myself"). On the other hand, industrial/utility users quantify all costs, including even corporate overhead charges. The analysis presented here provides for reasonable flexibility in choosing between these philosophies.

4.1 Capital Costs

The capital cost of a WECS installation is the sum of the following costs:

- the complete WECS unit, f.o.b. the factory
- delivery to the site
- provision of site access
- foundations and supporting structure
- assembly and erection
- interconnection to the load
- commissioning and check-out

For preliminary economic analyses it is common to represent all other elements of the installed system cost as a percentage of the WECS f.o.b. factory costs. The value of this "installation" percentage can vary significantly with the type, number, and size of the WECS, as well as with the location and topography of the site. For hundred-unit wind farms on relatively flat, accessible terrain, installation costs could be as little as 25% of WECS f.o.b. factory cost. For a single unit requiring crane erection at a rugged isolated site, the cost for installation, connection, and commissioning could exceed the WECS f.o.b. factory cost.

4.2 WECS Cost per Unit Area

A common parameter used to specify installed cost of generating systems is "dollars per rated kilowatt." This is not appropriate for WECS because, for a given size rotor, different WECS manufacturers may install generators with quite different rated powers (i.e., different power loadings). However, in a given wind regime the amount of energy produced is much more dependant on rotor size than on generator rating. Thus, a more meaningful unit for expressing installed cost for WECS is dollars per unit of swept area ($\$/m^2$).

4.3 Operating and Maintenance Costs

The annual operating and maintenance (O&M) costs for a complete WECS system include costs of

- insurance premiums, licence fees, etc.
- rental of land, connection equipment
- periodic inspections and routine maintenance
- consumables (e.g., oil, grease, etc.)
- replacement parts and labour for repairs

Such costs are often expressed as a percentage of the WECS hardware costs; this reflects the typically minimal maintenance requirements of site preparations, foundations, and interconnection systems. However, for the present analysis, it is convenient to express annual O&M costs as a fraction of **total** installed system costs, choosing, of course, appropriately lower numerical percentages to reflect the greater base value.

5.0 ECONOMIC CONSIDERATIONS

5.1 Fixed Charge Rate Economics

The total recurring annual cost of the WECS system is the sum of the cost of ownership and the cost of O&M. If both these costs are expressed as fractions of the total initial capital cost of the installed and commissioned WECS, one can write

$$\text{Annual Cost (AC)} = (\text{FCR} + \text{O\&M})\ \text{Capital Cost}$$

where

FCR = the fixed annual fraction of the initial total system capital cost (CC) required to amortize the debt at interest rate i in n years

$$= \frac{i(1+i)^n}{(1+i)^n - 1}$$

and

O&M = the levelized annual operating and maintenance cost expressed as a fraction of the initial capital cost of the complete installation (CC)

The cost of energy can be found by dividing the annual cost of owning and operating the equipment by the annual net energy output (AE)

$$COE = \frac{(AC)}{(AE)} = \frac{(FCR + O\&M)\ (CC)}{(AE)}$$

which, expressed in units common to electrical generation systems, is

$$¢/kWh = \frac{(FCR + O\&M)\ CC}{kWh/yr} \times 100$$

or, by conversion into units common to thermal energy systems*

$$\$/GJ = \frac{(FCR + O\&M)\ CC}{GJ/yr}$$

and, as 1.0 GJ = 278 kWh,

$$¢/kWh = \left(\frac{(FCR + O\&M)\ 100}{278}\right)\left(\frac{CC}{GJ/yr}\right)$$

$$= 0.36\ (FCR + O\&M)\left(\frac{CC}{GJ/yr}\right)$$

$$\equiv f\left(\frac{CC}{GJ/yr}\right)$$

where

$f \equiv 0.36\ (FCR + O\&M)$, a factor that accounts for economic parameters and conversion units

and

$\frac{CC}{GJ/yr}$ = the capital cost of an installed energy system per annual gigajoule of energy output

TABLE 2 evaluates (FCR + O&M) for ranges of the three independent parameters i, n, and O&M.

---

* Wind-generated electricity can be used for space or water heating. In these applications it is often desired to compare wind energy to other sources of low grade thermal energy such as solar heating. For convenience, units appropriate to both thermal and direct electric applications are presented.

TABLE 2. Annual cost factor (FCR + O&M) For various values of O&M, interest rate, and system life

System life n (yr)	O&M* (% of CC)	Interest rate i = 8%	12%	16%
	0	0.1490	0.1770	0.2069
	1	0.1590	0.1870	0.2169
10	2	0.1690	0.1970	0.2269
	3	0.1790	0.2070	**0.2369**
	0	0.1019	0.1339	0.1687
	1	0.1119	0.1439	0.1787
20	2	0.1219	**0.1539**	0.1887
	3	0.1319	0.1639	0.1987
	0	0.0888	0.1241	0.1619
	1	**0.0988**	0.1341	0.1719
30	2	0.1088	0.1441	0.1819
	3	0.1188	0.1541	0.1919

*O&M based on **total installed system** cost.

From Table 2, three scenarios might be chosen and values of the economic factor f computed as follows:

Optimistic: i = 8%, n = 30 yr, O&M = 1%, $\therefore$ f = 0.0356

Neutral: i = 12%, n = 20 yr, O&M = 2%, $\therefore$ f = 0.0554

Pessimistic: i = 16%, n = 10 yr, O&M = 3%, $\therefore$ f = 0.0853

The inverse of the annual cost factor can be used as a rough guide to the **allowable** total capital cost of a WECS system to provide a given cost of energy. For example, assuming the NEUTRAL scenario, (FCR + O&M) = 0.1539, and hence the allowable installed cost of a WECS to produce energy valued at D $/yr is $(D ÷ 0.1539). If the energy value D were $1000/yr then the WECS must be purchased and installed for $6500. Similarly, if an OPTIMISTIC or PESSIMISTIC scenario was postulated, the allowable installed cost would be $10100 or $4200, respectively.

6.0 WECS COST EFFECTIVENESS

Combining the roughly-optimum power loadings for various average windspeeds as developed in Section 3.3, and the economic relations developed

in Section 5.1, one can create a map of wind energy cost as a function of average wind velocity for a variety of different WECS unit costs as follows. From FIGURE 8a choose an annual average wind velocity (8 m/s) and, for the appropriate roughly-optimum power loading (1000 W/m^2), read off an annual unit energy output (1.39 $MWh/yr \cdot m^2$). Express the annual unit energy output as $1.39 \times 3.6 = 5.00$ $GJ/yr \cdot m^2$ and postulate a unit windmill cost ($\$500/m^2$) to obtain capital cost per unit of energy output ($500\ \$/m^2 \div 5.00\ GJ/yr \cdot m^2 = 100\ \$/GJ \cdot yr$. Repeating this gives TABLE 3.

TABLE 3. Capital cost per unit annual energy output of well-designed WECS with roughly optimum power loading ($/GJ•yr)

Annual average windspeed (m/s)	Unit cost of installed WECS ($/m²)				
	250	500	1000	1500	2000
4	397	794	1587	2381	
5	202	405	810	1215	
6	115	230	461	691	
7	73	146	291	437	582
8	50	100	200	300	400
9	38	76	153	229	306
10	32	63	126	190	252

These data are plotted in FIGURE 10, together with the sub-family of curves for fixed (not roughly-optimum) power loadings for the $\$1000/m^2$ case.

Also shown on FIGURE 10 are three scales giving energy costs in ¢/kWh corresponding to the installed cost per annual unit energy output for the three economic scenarios chosen somewhat arbitrarily in Section 5.1.

WECS manufacturers' brochures usually include values of rated power, rotor diameter, and f.o.b. factory cost. Installed WECS unit cost can therefore be determined by multiplying f.o.b. cost by an appropriate factor to account for transportation, installation, connection, and commissioning costs, and then dividing by the swept area computed from the blade diameter or other rotor geometric data. The appropriateness of power loading for the site under consideration should be checked by dividing the maximum power rating by the swept area and comparing the quotient to the values suggested in Section 3.3. If the power loading seems appropriate (and if the candidate turbine is well designed) the cost of energy from the proposed installation can be read from the chosen economic scenario opposite the intersection of the Installed WECS Unit Cost curve and the Annual Average Windspeed of the candidate site.

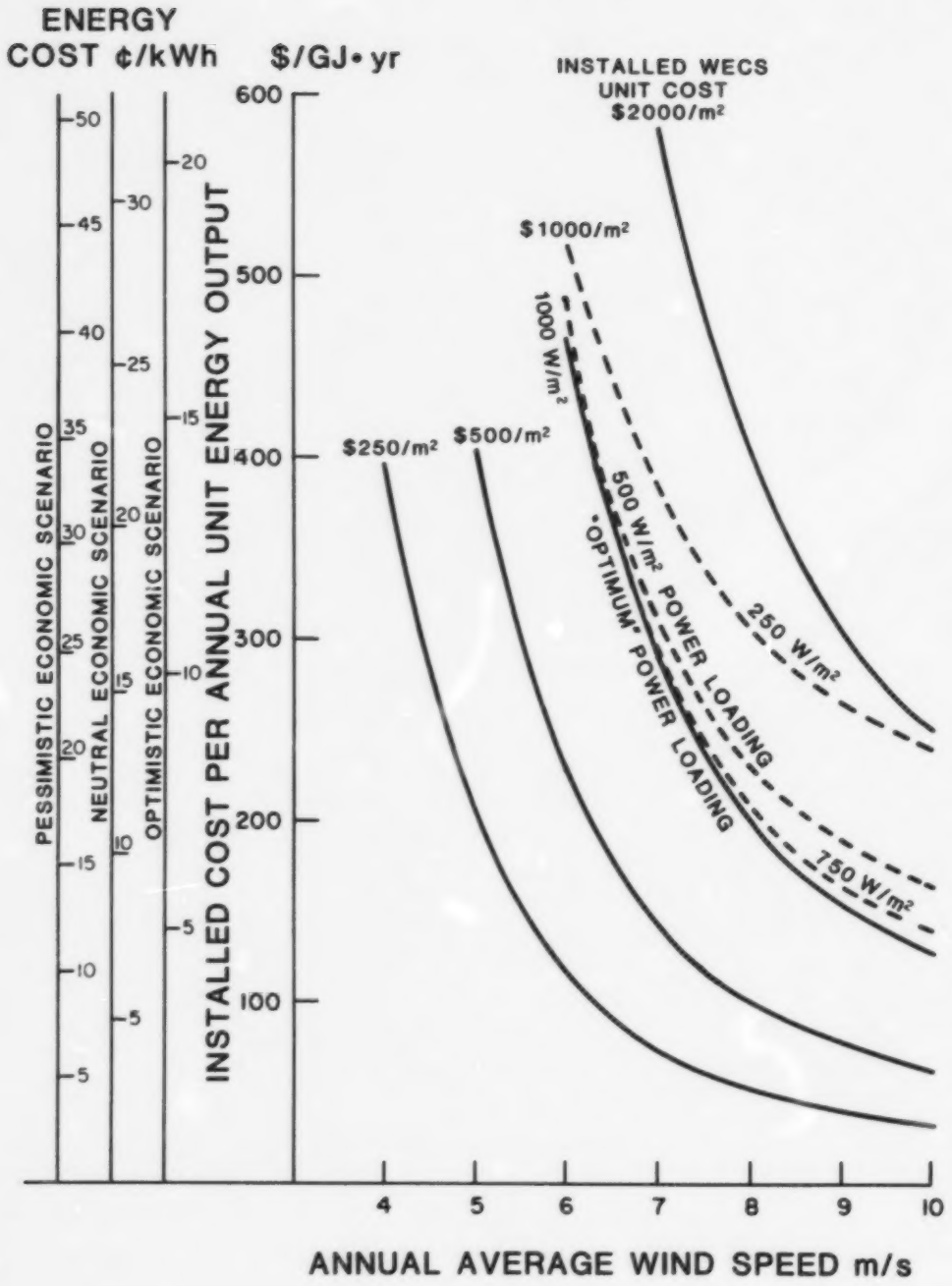


Fig. 10. WECS installed cost per annual unit energy outpu

Example

Consider a Brand X wind turbine rated at 15 kW, with a 25-foot diameter rotor, that costs $22 000 f.o.b. the factory. The proposed site has an annual average wind velocity of about 6 m/s.

(i) Estimate installed/commissioned cost as being 1.75 × factory cost, i.e., $38 500

(ii) Compute swept area

$$A = \frac{\pi}{4} \times \left(\frac{25}{3.28}\right)^2 = 45.6 \text{ m}^2$$

(iii) Compute installed WECS unit cost

$$\text{Unit Cost} = \frac{38500}{45.6} = \$844/\text{m}^2$$

(iv) Check power loading

$$\text{Power Loading} = \frac{15000}{45.6} = 328 \text{ W/m}^2$$

(which is satisfactory for 6 m/s)

Then from Figure 10:

Installed Cost per Annual Unit Energy Output		= $390/GJ·yr
Cost of Energy:	Optimistic Scenario	= 13.5¢/kWh
	Neutral Scenario	= 22¢/kWh
	Pessimistic Scenario	= 33¢/kWh

Note that the allowable annual O&M costs inherent in the three economic scenarios are $385, $770, and $1155 for the Optimistic, Neutral, and Pessimistic scenarios, respectively.

All of the foregoing considerations can be combined into a single multi-parameter plot and nomograph as shown in FIGURE 11. The graph on the right-hand side summarizes performance of current typical well-designed WECS, including the frequently quoted Plant Factor which defines the fraction of rated power that is produced on average by the candidate WECS in the wind regime under consideration. The four nomograph scales on the left describe the economic factors, including continuously variable scales for the annual cost factor and the capital cost per unit swept area. These scales are used by drawing straight lines between the A and B scales, and between the B scale and the ordinate scale of the performance plot (marked C).

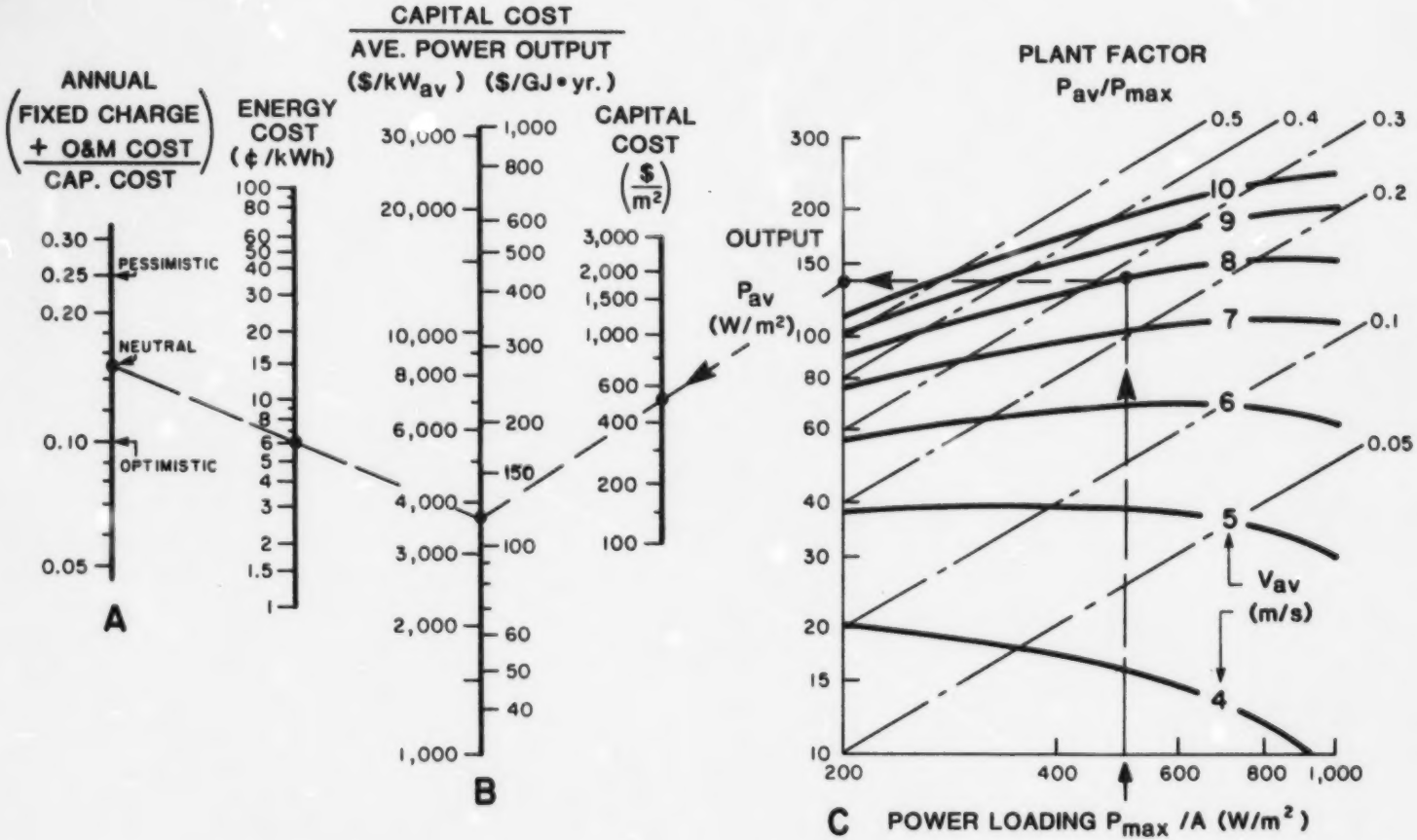


Fig. 11. Wind turbine performance and cost-effectiveness chart

The use of the Wind Turbine Performance and Cost Effectiveness Chart is best explained by example, as on FIGURE 11. From manufacturer's data, estimates of installation costs, knowledge of site winds, and perception of economic conditions the following input values are established:

$$P_{max}/A = 500\ W/m^2$$
$$V_{av} = 8\ m/s$$
$$\text{Installed cost} = \$500/m^2$$
$$\text{Economic scenario} = \text{Neutral}$$

The performance plot is entered at a power loading of 500 W/m^2. Going up to the 8 m/s windspeed line indicates a Plant Factor of 0.28 and an Average Unit Power Output of 140 W/m^2. It can also be noted that, at 500 W/m^2, the power loading of the candidate windmill is somewhat below optimum, as increasing the power loading to 800 W/m^2 (say by purchasing the "optional higher rating model for very windy areas") increases P_{av}/A to 150 W/m^2 (from 140 W/m^2) even though Plant Factor reduces to 19% (from 28%).

Projecting a straight line from 140 W/m^2 on performance scale C through the \$500/m^2 Installed Capital Cost nomograph line gives a capital cost per unit average power output of \$3700/kW_{av} or \$120/GJ·yr. Presuming the Neutral economic scenario with a corresponding annual cost factor of 15%, one can obtain the cost of energy (6¢/kWh) by joining the appropriate points on nomographs A&B.

7.0 CONCLUDING REMARKS

Though hardly profound, the following general observations can be made from studying FIGURES 10 and 11.

The strong dependence of power output on annual average windspeed can be noted from the performance plot of FIGURE 11, despite the use of a logarithmic ordinate scale which results in the higher windspeed curves being closer together. This sensitivity justifies careful site selection and consideration of tower height. Appropriate choice of power loading for a given wind regime is seen to be more important for poor or very good sites, and less critical for moderate wind regimes with 5 to 6 m/s annual average windspeed.

For any given average power output it can be seen that Plant Factor is strongly dependent on power loading. High power loading tends to result in relatively short periods of high power output, whereas low power loading may give the same average power (and hence the same energy output) but in longer periods of somewhat lower power production. This "output power

spectrum" is of considerable importance if the wind system rating is a substantial fraction of the total generation capacity, or if the application involves energy storage.

The linear relation of the total capital cost of the installed WECS to system cost-effectiveness is self evident from FIGURE 10. Expressed in other terms, however, halving the installed capital costs reduces the annual average windpseed required to achieve a given level of cost-effectiveness by 1 to 2 m/s. It is interesting to note the consequent fact that an uncertainty of 1 to 2 m/s in site average windspeed gives the same doubt in economic viability as not knowing the system capital cost to within a factor of two.

The effect of the presumed O&M and financial scenario is seen directly from the slope of the line drawn between nomographs A and B on FIGURE 11. Although often difficult to quantify, the longevity, interest rate, and O&M parameters must be carefully and realistically chosen in order to predict meaningful costs.